Pacific Gas and Electric Company

Les Guliasi
Director
State Agency Relations

Mail Code B29L
Pacific Gas and Electric Company
P.O. Box 77000
San Francisco, CA 94177-0001

415.973.6463
Fax: 973.9572

November 8, 2005

ELECTRONIC DELIVERY

California Energy Commission
Docket Office
Attn: Docket No. 04-IEP-1K
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512

Re: Comments of Pacific Gas and Electric Company

Pacific Gas and Electric Company (PG&E) respectfully submits the following comments on the Committee Draft Transmittal of the 2005 Energy Report Range of Need and Policy Recommendations to the California Public Utilities Commission.

Thank you for considering our comments. Please feel free to call me at (415) 973-6463 if you have any questions about this matter.

Sincerely,

Les Guliasi

LGG

Enclosure

Pacific Gas and Electric Company Comments on
The California Energy Commission's
Committee Draft Transmittal of 2005 Energy Report Range of Need and Policy Recommendations to the California Public Utilities Commission
Draft Transmittal Report

Introduction

PG&E takes this opportunity to comment on the Committee Draft Transmittal of *2005 Energy Report* Range of Need and Policy Recommendations to the California Public Utilities Commission, Draft Transmittal Report (CEC-100-2005-008-CTD) ("Draft"). PG&E appreciates the hard work and extensive discussion among the Energy Report Committee, CEC staff, and stakeholders that has preceded this Draft. Unfortunately, the Draft includes recommendations on resource requirements and policies that are not factually supported in this proceeding. As discussed below, PG&E respectfully requests that the Draft's conclusions on resource be revised in order to ensure the resource requirements are consistent with the CEC's technical analysis and promote the development of necessary, cost-effective, and environmentally beneficial generation. Additionally, PG&E believes that many of the policy recommendations included in the Draft are more appropriately discussed in the CEC IEPR report. Finally, PG&E recommends the Draft be revised to provide a more detailed evaluation of the cost impacts of the included recommendations and the subsequent costs to consumers.

In addition to these comments on the Draft, PG&E provides additional comments to the proposed revised Tables included in Appendix B, provided by CEC staff on November 7, 2005. PG&E appreciates the opportunity afforded by the Committee, acting upon PG&E's recommendation at the November 4, 2005, Committee hearing, to enable the IOUs and interested parties to confer with CEC staff to clarify the information presented in the Tables accompanying the Draft Transmittal Report. This extra step in the process was necessary to ensure that the Draft is credible and useful for resource planning in the CPUC's 2006 Long Term Plan proceeding. Our comments to the revised table are included in Appendix A of this document.

General Comments

This genesis of this report was CPUC President Peevey's assigned commissioner's rulings (ACRs) of September 2004 and March 2005 that the CEC would determine the appropriate level and range of resource needs for the 2006 long-term plan (LTP) for each investor-owned utility (IOU) within the IEPR process. PG&E and many other parties expected this process to follow the successful but informal cooperation between the CPUC and the CEC in assessing each utility's 2004 LTP, which made good use of the CEC staff's extensive resource planning knowledge. In short, PG&E expected that the Draft would provide an update on the forecasts in each utility's approved 2004 LTP, based on known and foreseeable changes since 2004, which have been expected to be modest. Instead the Draft presents forecasts that sometime refer to physical capacity and at other times to contractual capacity; that contradict other CEC assessments of resource need, and that mix new public policy discussion with what was supposed to be an objective, quantitative-based exercise.

PG&E commented recently on the new public policy positions reflected in the Draft, especially in the areas of Distributed Generation and Combined Heat and Power. (See PG&E's comments of October 14, 2005 on the Draft IEPR.) Many of these new public policy recommendations have been inserted into the Draft, and, thus, we reiterate these comments in brief here. We believe the public policy positions should be removed from the Draft as they are outside the scope of this part of the IEPR proceeding.

The Draft's recommendations for PG&E requirements contradict all other analyses of Northern California resource needs

The Draft's determinations of resource need and requirements contradict all other analyses of Northern California requirements, including the CEC's own July, 2005 analysis in this proceeding (California and Western Electricity Supply Outlook, Staff Report[1]). In particular, Table B-5 of the Draft presents PG&E-area "Base Demand Case" capacity requirements for the period 2009-2016, including a need for over 4,000 MW of new resources in 2009, 7,300 in 2010 and increasing dramatically beyond this timeframe.

This assessment is significantly different from the CEC's July, 2005 analysis, which projects that Northern California is adequately resourced through 2010. Further, the July analysis comports with the CEC's adopted 2004 Update to the Energy Report of a year ago, which reported that the PG&E area would have well in excess of 15% planning reserves through 2008 (based on an expected case)[2]. Additionally, the July 2005 WECC Power Supply Assessment projects Northern California will have a reserve margin of over 17% through 2009.[3] PG&E notes that it provided the same information on load and resources that was used in all of the 2005 analyses.

Resource Accounting Tables present regional contractual resource requirements, not IOU physical requirements

In order to ensure that the Draft is credible and useful for resource planning, PG&E recommends that it be edited to clarify that the resource need presented represents the ***contractual requirements for load serving entities*** (LSEs) in the IOU planning area and not the physical requirements for new generating capacity or the contractual requirements of individual IOUs. As discussed above, previous CEC and WECC analyses demonstrate that Northern California has sufficient physical resources to meet its total energy requirements for the next several years, and the need determinations provided in this

[1] California and Western Electricity Supply Outlook, Staff Report[1], CEC-700-2005-019, July, 2005
[2] Integrated Energy Policy Report 2004 Update, CEC-100-04-006CTF, October, 2004, Table A-3
[3] WECC 2005 Power Supply Assessment, presentation by Stan Holland, WECC, at July 26, 2005 CEC IEPR Hearing

Draft presenting a range of contractual resource requirements. This clarification was discussed in detail by the Energy Report Committee at the November 4, 2005 hearing on the Report.

The Report should also be revised to emphasize the need requirements are planning-area requirements, not individual IOU requirements. The annual Resource Accounting Tables included in Appendix B of the Draft present loads and resources owned and controlled by both utility and non-utility LSEs. According to PG&E's calculation the "Additional Non-Designated Need" presented on the tables reflect not only PG&E's resource position, but also the net requirements for all other LSEs in the PG&E-Planning Area.

The Draft overstates electric resource requirements

The Draft tables included in Appendix B presents "Additional Non-Designated Need" for the PG&E planning area that significantly overstates current electric resource requirements by ignoring planned resource additions. In 2005 PG&E applied to the CPUC to assume ownership and complete construction of the 530 MW Contra Costa 8 generating plant, and has executed several long-term contracts with renewable resources. Further, PG&E is currently in the process of evaluating bids to procure up to 2200 MW, as defined and approved in PG&E's last CPUC-approved long-term procurement plan. While this is briefly discussed in the Draft Report these resources are not represented on the tables, and procurement to the CEC recommended amounts would result in significant over-procurement.

The tables do not accurately represent regional supply and demand. The tables present total "Service Area Demand" for the IOU planning area, but for supply resources only includes the "claimed" capacity of generation rather than the total capacity available in the market. The table presents "existing capacities" for only those resources claimed by LSEs in their submitted supply forms, but many existing generation resources currently have no firm capacity sales contracts and, as such, this capacity would not have been claimed and is not included in this resource balance. The result is that requirements are overstated since available capacity not under contract, or new and un-contracted capacity that becomes available during the forecast period, is not considered to be regional resources. For example, PG&E's portfolio includes over 4000 MW of expiring DWR-contracted resources. It is highly unlikely that this generating capacity will disappear, and will be available for contract after the DWR contracts for this capacity expire.

Replacing aging power plants will neither meet customer requirements nor reduce costs

The Draft includes a policy recommendation that IOUs should replace capacity from what the CEC had deemed to be aging power plants. It assumes that these resources will be retired by 2012 and proposes that the investor owned utilities should replace this capacity, specifically proposing "To facilitate the retirement of these aging power plants, the Energy Commission has apportioned these 50 plants to the three IOUs based on their physical location, along with their existing capacity…."(p.46) This apportionment of new capacity requirements without consideration of utility need or cost raises several troubling concerns.

The Draft has failed to provide any basis for the retirement assumption. Most of the proposed retiring resources located in Northern California are not utility owned, and PG&E is unaware of specific retirement plans for these resources. If utilities were to prospectively replace these resources and they are not retired, the resulting stranded costs would be substantial. PG&E notes that it is planning to retire the Hunters Point Generating Station in 2006 and the Humboldt Bay Generating Station prior to 2010.

Further, requiring the utilities to replace this non-utility generation will result in subsidization of non-utility energy service providers and direct access customers by utility customers. The CEC reports that IOU loads represent approximately 60% of statewide electricity demand, yet expects them to replace all of the aging plant capacity, much of which is currently sold to non-utility LSEs. The likely result of this will be that utilities would incur the cost of replacing this generation, and the existing, less-expensive generation will be contracted by non-utility participants.

Load forecast will require updating for CPUC Long-Term Procurement Plan

The Draft recognizes that some of the information used in constructing the range of need shown in the tables in this report will be out of date by the conclusion of the CPUC's 2006 long-term procurement proceeding (LTPP). The Draft offers the following guidelines for when and how adjustments to the numbers would be appropriate.

> In terms of the demand forecasts, the Energy Commission believes that the revised staff forecast provides the appropriate basis for the 2006 LTPP. A biennial proceeding focused upon the long-term cannot be a good source of short term demand forecasts that are updated frequently for recent historic data and near-term expectations. Such near-term demand forecasts are appropriate for many operating activities. The Energy Commission does not anticipate any conditions in which an update of the staff revised forecast for the years 2008 and beyond would be appropriate….(page 55)

PG&E disagrees with the above statement, and believes that adjustments are appropriate. The range of annual average growth rates for PG&E energy and peak demand over the period 2004-2006, as shown in Table 11, page 75, appear reasonable. However, as the long term planning process moves into the CPUC phase, these growth rates must be "calibrated" to recent levels of observed demand in order to produce more realistic estimates of MWh and MW demand during the forecast horizon. Staff's revised projections, as shown in the Draft, are currently calibrated to 2004 observed demand.

Allowing for another update, which could still rely on the staff's solid growth rates, will avoid the very real possibility that staff's 2008-2016 projections in MWh or MW will be inconsistent with more recent observed data on energy use and peak demand that is not now available but may be available prior to the filing of the IOU's 2006 long-term procurement plans.

Energy Efficiency should be treated in a consistent fashion throughout the forecast horizon

The current analysis underlying the Integrated Energy Policy Report does not include PG&E's full forecast of energy efficiency savings in a manner consistent with the way PG&E treats this demand side resource. The Draft report treats forecasted energy efficiency savings beyond 2008 as a supply-side resource. There are two problems with such treatment: (a) it makes comparisons difficult; and (b) it incorrectly reduces the cost-effectiveness of future energy efficiency programs, since they no longer receive the credit they deserve for reducing the need for reserves.

The inconsistent treatment of targeted energy efficiency savings in the Draft creates confusion. For example, Table 6 suggests that the LSE's aggregate forecasts for the PG&E planning area are lower than the staff's projection. However, as PG&E pointed out in its June 30th workshop presentation, the forecasts are not comparable. If placed on a comparable basis, the aggregate LSE projections for PG&E's planning area are very likely to be above, not below, the levels projected by CEC Staff.

PG&E requests that the CEC avoid confusion by modeling energy efficiency savings as a reduction to projected demand throughout the forecast period.

The Draft must distinguish between customer-scale distributed generation (DG) and large combined heat and power (CHP) generating facilities

As PG&E has noted in comments on the Draft IEPR, the IEPR Committee has used the terms "Distributed Generation ("DG") and Combined Heat and Power ("CHP") interchangeably. The lack of clarity about when the CEC refers to DG and when the CEC refers to CHP is confusing and can even be misleading.

The terms "DG" and "CHP" encompass a very broad range of facilities with varying levels of efficiency, air emissions and other environmental impacts, and system impacts, from small residential photovoltaic systems to very large cogeneration plants. As such, policies should be developed with a careful consideration of the very different forms of DG and CHP.

PG&E recommends that the final Report include a clear definition of distributed generation, and continues to recommend the following:

> Distributed generation is electricity produced on a customer site from generators under 10 MW in size that are interconnected to the utility distribution system and

that are designed predominantly to serve load at the customer site or over the fence to one or two adjacent customers.

PG&E appreciates the CEC's effort to hold utilities revenue neutral through reinstitution of an Electricity Revenue Adjustment Mechanism. However, PG&E is disheartened by the implication that PG&E is somehow opposed to CHP and other DG because the policies proposed by the CEC run counter to PG&E's shareholder interests. This is not the case. As we explained to the CEC in a letter to Commissioner Pfannenstiel on September 8, 2005, PG&E's shareholders are indifferent to the amount of DG installed by our customers because various revenue adjustment mechanisms ensure that PG&E recovers any costs created by departing load..

PG&E supports DG as one of the choices our customers can make to meet their energy needs. Consistently throughout the IEPR process, PG&E has been supporting inclusion of cost benefit analysis in the decision making process. We have also consistently called for thoughtful policy decisions that are informed by cost benefit analysis rather than policy recommendations that support DG or CHP without including cost considerations. We do this because any uneconomic policy recommendations will have a negative impact on our customers (NOT our shareholders). If there is to be such an impact, it should be in carefully considered situations only, where the total resource costs justify it or where overwhelming policy considerations justify limited impacts on other customers.

Existing and new CHP are not necessarily fuel-efficient, cost-effective or environmentally superior to other thermal generation

The Draft makes several policy recommendations for CHP that are essentially the public policy advocacy positions of current cogeneration companies: that the IOUs should buy all electricity from CHP plants in their territories under standard offer contracts of at least ten years duration; that the CEC and CPUC should develop a yearly procurement target for CHP; and that the IOUs should be required to schedule CHP power at cost.

PG&E objects to the Draft adopting as recommended public policy these recommendations, without having considered the views of other stakeholders and interested parties. During the October 6, 2005, Committee hearing on the 2005 IEPR Committee Draft Report PG&E offered oral and subsequent written comments regarding its position on the benefits as well as the difficulties encountered with its cogeneration experience. None of PG&E's observations are reflected in the Draft.

The CPUC has jurisdiction under PURPA to establish wholesale rates for the purchase of power from qualifying facilities only. Not all CHP qualifies as QF power; thus the Draft's recommendation that the CPUC establish avoided cost rates and contract terms for the sale of all power from CHP may run afoul of federal law. For non-QFs selling to the utilities at wholesale, FERC has exclusive jurisdiction to set just and reasonable rates. As we discuss below, FERC has jurisdiction to determine which cogenerators will be certified as QFs.

There are several good public policy reasons to reject or restrict the carte blanche long-term extension of existing QF cogeneration contracts and to oppose an open ended standard offer for new cogeneration facilities instead of market-based pricing and terms. PG&E has detailed its concerns in this area in our response to the Draft IEPR and extensively in our Avoided Cost testimony before the CPUC.[4] We reiterate these arguments briefly here.

First, a cost-effectiveness test (as the Draft IEPR concluded) is essential. Such a test would reveal that efficient cogeneration projects are in fact cost effective, can be and are economically competitive with other generation sources. Efficient cogeneration projects do not need the help of governmental programs and public subsidies. On the other hand, no public benefit is realized from economically propping up old, inefficient, cogeneration projects with outdated and inferior environmental controls, many of which are owned by large industrial and oil producing companies.

Second, the issue of expiring QF Power Purchase Agreements (PPAs) is presently being considered by the CPUC in its QF Avoided Cost Proceeding. PG&E submitted testimony in that proceeding, examining the validity of cogeneration industry claims regarding the benefits realized from cogenerated power in California. In its testimony PG&E rebuts these representations and shows that the most cost effective manner of providing for the state's future energy supply needs is not through the extension of the PPAs of old, inefficient cogeneration plants, but through the construction of state-of-the-art modern generation facilities.

Third, the capacity of older cogeneration units nearing the end of their contracts in PG&E's territory is not large. We think many of these plants may be able to continue generating electricity even if paid only market prices in the future, but even if we are wrong and the cogenerators fail to continue after their contracts expire, we would only be losing about 500 MW through the year 2010. This potential lost capacity is a small fraction of the capacity of new, already licensed but yet-to-be-constructed generation projects in PG&E's service area.

Fourth, the whole question of what types of CHP will be certified by FERC as qualifying facilities under PURPA is under review as part of FERC's implementation of the 2005 Energy Policy Act. The outcome of that review is uncertain, but will probably decrease the range of cogeneration facilities deemed to be QFs and eligible for avoided-cost pricing. The CEC and the CPUC should not act hastily to order the utilities to enter into contracts with facilities which may be determined to have too small a thermal load to be qualified as QFs.

---

[4] See PG&E's prepared and rebuttal testimony in the CPUC's R. 04-04-003 and 04-04-025 of August 31, 2005 and October 28, 2005 regarding Qualifying Facilities Policy and Pricing Issues.

Finally, giving CHP a set aside while making renewables compete through RFOs would give CHP an advantage over renewables and would be inconsistent with the concept of renewables as the rebuttable presumption.

Conclusion

PG&E believes that the Draft should be revised to present a range of utility contractual resource needs as envisioned by CPUC President Peevey's ACR. PG&E believes that such revisions must and should be included before the Draft is finalized and transmitted to the CPUC.

Appendix A

Pacific Gas and Electric Company
Comments on CEC IEPR
Proposed Revised Annual Aggregated Energy Resource Accounting Tables and Annual Aggregated Capacity Resource Accounting Tables

Pacific Gas and Electric Company (PG&E) appreciates the opportunity to comment on the CEC Staff's proposed revised annual Aggregated Energy Resource Accounting Tables of November 7, 2005. These tables, included as Appendix B to the Committee Draft Transmittal of 2005 Energy Report Range of Need and Policy Recommendations to the California Public Utilities Commission, Draft Transmittal Report, present the capacity and energy balances for the period 2009-2016 for the states load serving entities (LSEs). PG&E appreciates the effort that staff has expended developing these tables and understands the difficulty in presenting information is a comprehensive manner. PG&E provides the following recommendations for revising the tables in order to increase the clarity of the information so that it may be better understood by all reviewers and users.

First, PG&E recommends that the final Appendix B include a discussion of the methodology used in developing the tables. While discussion of the methodology is included in Chapter 5 of the Report, it would be very helpful to the reader of the tables to include the relevant methodology along side the tables.

Second, PG&E recommends re-arranging the tables in order to present the "Aging Plant Replacement" information at the bottom of the sheet and not on the table itself. PG&E appreciates that the Committee wants to present the capacity and energy from Aging Plant Replacement with the contractual resource need information, but the current table design is confusing. Aging Plant Replacement capacity and energy values are not used in any calculations on the table, and it is unclear why this information resides on the table. PG&E believes the CEC goal of presenting this information with the resource need information is achieved by simply including it beneath the table.

Finally, PG&E recommends the tables be renamed "(IOU***)-Planning Area*** (Scenario) Demand Case" rather than the current "(IOU) (Scenario) Demand Case" in order to reflect the nature of the information presented on the tables. The current table titles are something of a misnomer, as the tables include a composite of utility information and non-utility information. While PG&E cannot speak to the comprehensiveness of the non-IOU information, the tables do not present PG&E-specific demand case data. Changing the tables name would clarify for the reader that they are not examining utility–specific information.